ACCESSION #: 9610210166
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Calvert Cliffs, Unit 1 PAGE: 1 OF 13

DOCKET NUMBER: 05000317

TITLE: Manual Reactor Trip Due to Increasing SG 11 Water Level
EVENT DATE: 11/09/95 LER #: 95-005-01 REPORT DATE: 10/10/96

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
20.2203(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
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COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: SJ COMPONENT: DCC MANUFACTURER: F120
E ESB PDS
REPORTABLE NPRDS: Y
N

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

END OF ABSTRACT

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On November 9, 1995 at 1457 hours, an alarm notified Operators of a high Steam Generator (SG) 11 level (+15 inches). Operators verified that SG 11 level was increasing and attempted to place its feedwater regulating valve controller in the manual mode without success. Steam Generator 11 level increased to approximately +35 inches and the reactor was manually tripped.

The cause of the trip was a failure of digital feedwater control module FIC-1111. Testing determined the most probable cause was electromagnetic interference. A comparison of the as-installed input/output/power cabling found it was not shielded in accordance with the vendor technical manual. Electromagnetic interference can induce a fault causing the FIC-1111 output signal to ramp up, slowly opening the SG 11 feedwater regulating valve.

END OF ABSTRACT

I. DESCRIPTION OF THE EVENT

On November 9, 1995 at 1457 hours, a computer alarm in the Calvert Cliffs Control Room alerted operators to a high Steam Generator (SG) 11 level (+15 inches). By 1500, operators had verified via other indications that SG 11 level was indeed increasing and implemented Abnormal operating Procedure, AOP-3G, "Feed Malfunctions." Since the SG 11 Feedwater Control System did not appear to be properly controlling feedwater flow, operators repeatedly attempted to place its feedwater regulating valve (FRV) digital controller (FIC-1111) in the manual mode. The controller did not respond. At 1501, SG 11 water level had increased to approximately +35 inches and operators manually tripped the reactor.

After the manual reactor trip, operators initiated Emergency Operating Procedure EOP-0, "Immediate Post Trip Actions." Steam Generator Feed Pump 11 (SGFP) tripped on high discharge pressure at 1501:44. Steam Generator Feed Pump 12 was noted as not delivering flow due to its low speed. In accordance with EOP-0, operators manually tripped SGFP 12 and initiated the electric driven auxiliary feedwater (AFW) pump (AFW 13) at 1505.

The trip recovery was complicated by a failure of the second stage moisture separator reheater (MSR) source valves (1-MS-4025-MOV and 1-MS-4026-MOV) to close as designed after the reactor tripped. The open MSR source valves acted to increase the rate of SG steaming, causing SG pressures and Reactor Coolant System (RCS) temperature to decrease at higher than desired rates.

At 1507, AFW flow was throttled to control decreasing RCS temperature. The RCS cold leg temperature (Tc) was approaching 525 degrees Fahrenheit due to the open MSR source valves. At 1510, SG pressures had fallen to the EOP-0 action limit of less than 800 psia. In accordance with EOP-0, Operators manually closed the main steam isolation valves (MSIVs), and took manual control of the atmospheric dump valves (ADVs) to control RCS temperature. Tc reached a minimum of 524 degrees Fahrenheit.

During the plant stabilization that followed, operators had trouble maintaining a positive SG 11 level trend because ADV 11 was relieving steam at a faster rate than ADV 12. Both ADVs are operated in tandem from the same controller in the Control Room. Operators made some minor adjustments to AFW flow rate in an attempt to restore a positive level trend to SG 11. However, their primary concern at this point was to restore and maintain RCS Tc to greater than 525 degrees Fahrenheit. They were careful not to feed too much cold AFW water into SG 11 and further cool down the RCS. By 1513, Tc had recovered to greater than 525 degrees Fahrenheit.

Operators continued to adjust AFW flow to the SGs and dump steam through the ADVs to control RCS heat removal. The difference in ADV 11 and 12 steaming rates resulted in SG 11 level falling while SG 12 level recovered. Throughout this period, Operators were focused on maintaining RCS Tc above 525 degrees Fahrenheit. At 1527, an Auxiliary Feedwater Actuation System signal was generated due to low SG 11 level (below -170 inches) starting the steam-driven AFW pumps and restoring an increasing level trend in SG 11. Thereafter, the plant recovery proceeded normally, and at about 1700, operators exited EOP-1, "Reactor Trip."

II. CAUSE OF EVENT

A Significant Incident Finding Team was established after the event occurred to investigate, determine the causes, and recommend corrective and preventative actions. The Significant Incident Finding Team determined the following causes and problems were important to the event.

A. FIC-1111 FAILED LEADING TO THE SG 11 OVERFEED CONDITION

Initial investigation into the cause of the feedwater flow problem found that the Feedwater Control Module FIC-1111, a digital controller, had an, "Error 4, RAM Bad," message on its local digital display. The FIC-1111 controller is a Fischer Porter (FP) 2000 series digital controller. The controller was quarantined to avoid a potential loss of data pending further investigation. Post trip troubleshooting and analysis found that the output signal from FIC-1111 was linear with a slowly increasing signal trend. This resulted in the FRV to SG 11 slowly opening, leading to the increasing water level.

Electrical and Controls personnel attempted to insert commands to clear the error message without destroying any evidence, but the controller did not respond. The controller was downpowered and repowered and the error message cleared. The controller then appeared to be functioning properly. Its program was downloaded, checked, and found to be satisfactory.

The digital and power supply inputs into the controller were verified as operating satisfactorily. It was also verified that no work was in progress in the vicinity of the FRVs or the controller prior to the controller failure.

A letter from the vendor indicated that the Error 4 "RAM Bad" error code is a rare occurrence and that after such an error message the controller should be removed from service and tests run at a repair facility to determine the cause. Baltimore Gas and Electric Company and the vendor expected the FP 2000 series controller to drift at an unpredictable rate after a failure of this type rather than the linear slowly increasing output signal trend that was observed.

The failed controller FIC-1111 was sent offsite to Fischer Porter for a failure analysis. A troubleshooting test plan was developed and executed jointly by Baltimore Gas and Electric Company and Fischer Porter. The results indicate that electromagnetic interference (EMI) was the most probable cause of the failure. The "Error 4" failure code, and several other failure codes were reproduced in the lab by imposing a pulsed EMI signal on the controllers various input, output, and power cabling. A comparison of the as-installed configuration to the recommendations in the vendor technical manual revealed a significant discrepancy. The vendor technical manual calls for shielded input, output, and power cabling while the controller actually had unshielded cabling.

The underlying cause was inadequate implementation of vendor technical manual recommendations concerning cable shielding during implementation of the digital feedwater upgrade project. The project team assumed that conformance with in-house cable-routing standards would satisfy all design requirements. The in-

house standard is primarily a cable separation/redundancy standard and does not satisfactorily address EMI, radio frequency interference (RFI) or grounding.

The project did recognize the potential for RFI and conducted RFI area surveys prior to the modification. Electromagnetic interference is however, a highly localized and transient phenomenon whose detection and measurement is very difficult, making EMI area surveys impracticable.

B. SGFP 11 AND 12 TRIPPED

Directly after the plant trip, operators and the system engineer responsible for the main feedwater system arrived at the FRVs to monitor their performance. They observed that both FRV bypass valves were open to the proper post-trip intermediate position. The system engineer was also able to observe that SGFP 11 had tripped, and that SGFP 12 was idling with its turbine governor valves closed and then later observed the tripping of SGFP 12. Review of plant computer data indicated that SGFP 11 tripped on a high discharge pressure, and SGFP 12 was manually tripped from the control room.

By design following a reactor trip, both FRVs immediately shut and the SGFPs immediately begin to ramp down in speed to minimize SGFP discharge pressure. Apparently during this trip, the rapid shutting of the FRVs exceeded the ability of the SGFP runbacks to maintain SGFP discharge pressures less than the discharge pressure trip setpoint.

The duration of the high feedwater discharge pressure trip signal is dependent on the flow seen by each SGFP and the running speed of its turbine. After this trip, SGFP 11 electrical trip solenoid valve picked up and shut its turbine stop valves. The SGFP 12 turbine stop valves did not go closed, but rather, the speed control system had automatically shut its turbine governor valves. The speed control system is designed to automatically shut the governor valves on an active turbine trip. The response time difference between the reaction of the governor valve speed control system and the reaction time of actually picking up

tripping SV was significant for SGFP 12 because the SGFP 12 discharge pressure spike barely reached the trip setpoint.

C. THE MOISTURE SEPARATOR SOURCE VALVES

The failure of the MSR source valves to close after the trip, as designed, complicated the plant post-trip shutdown. Normally, after a reactor trip from power levels of greater than 63 percent, the steam dump and turbine bypass valves fully open. When T(av) falls to approximately 548 degrees Fahrenheit, the ADVs and turbine bypass valves begin to automatically modulate. The ADVs modulate to maintain RCS T(av) to between 535 and 540 degrees Fahrenheit while the turbine bypass valves modulate to maintain SG pressure to between 895 and 900 psia.

The open MSR second stage source valves disrupted control of SG pressure by providing an unmodulated steam discharge path from the SGs. This resulted in a high rate of removal of energy from the SGs and the RCS and ultimately led to the need for operators to close the MSIVs and take manual control of the ADVs in order to control RCS temperature.

Troubleshooting found a problem with a differential pressure switch that provides the closure signal to both of the MSR second stage source valves. The differential pressure switch 1-PS-4025 was found to have a leaking bellows. The leaking caused the setpoint of the pressure switch to effectively change. The leaking also resulted in the formation of deposits inside the pressure switch causing some binding of the switch mechanical internals. The switch was replaced.

A review of the equipment database for Units 1 and 2 found that only one other switch of the same Manufacturer (Mercoid) and model exists at Calvert Cliffs, 1-PS-4026.

Review of the maintenance history for the switches found no previous failures. The failed switch appears to have been original plant equipment which failed after 20 years in service. During replacement of the failed pressure switch, 1-PS-4026 was

inspected and found failing in a manner similar to 1-PS-4025. The switch was replaced.

D. FEEDWATER BYPASS VALVE DID NOT INDICATE OPEN

Shortly after the trip, both feed regulating bypass valves (FRBVs) were visually verified by operators and the system engineer to be open locally at the valves themselves. However, control room indication did not change after the trip to show that FRBV 11 was open. The FRBVs indicate open when their indicating light changes from green (closed) to red and green (intermediate open). After the trip the FRBV 11 indication remained green.

Troubleshooting of the problem found a sticking limit switch was the cause of the problem.

E. ADVs RELIEVING AT DIFFERENT RATES

A calibration was performed on both ADV 11 and 12 I/P controllers. Atmospheric Dump Valve 11 I/P (I/P 3938) was found to be out of calibration at three percent higher than desired. This was probably the result of instrument drift since the prior refueling outage in the spring of 1994. Atmospheric Dump Valve 12 I/P controller (I/P 3939) was found to be within its calibration specifications, but 1.5% higher than desired.

A check of the valve mechanical positioners found the ADV 11 positioner controlled the valve full stroke from 3-15 psi input. The ADV 12 positioner controlled the valve full stroke from 4-16 psi input. Both valves I/P controllers receive the same controller input. The net result of the difference in I/P setpoints and valve mechanical positioner alignments was that ADV 11 went to a higher position and relieved steam at a faster rate than ADV 12 with the same input signal. Proper adjustment of ADVs 11 and 12 is important because they operate in tandem from a single controller in the Control Room.

Both ADV control circuits were realigned and stroked to ensure they both lifted to the same position.

III. SAFETY IMPLICATIONS

A. SAFETY CONSEQUENCES

This event did not result in a significant challenge to plant safety. The event that initiated the reactor trip was a SG 11 overfeed due to the FIC-1111 failure. The resulting increasing SG 11 level was conservatively mitigated by plant operators who manually tripped the reactor at a SG 11 level of +35 inches. Had the operators not manually tripped the reactor, an automatic-turbine trip followed immediately by an automatic reactor trip would have occurred at SG 11 level of +50 inches. The plant is designed to automatically trip and be safely recovered from a high level in either or both SGs without any adverse effects on the plant.

B. POTENTIAL SAFETY CONSEQUENCES

There were several complicating factors surrounding this trip. Specifically;

1. The MSR second stage source valves failed to close after the trip as designed, increasing the rate of SG steaming, and causing SG pressures and RCS temperature to decrease. Ultimately, this problem required operators to close the MSIVs and use the ADVs to control RCS temperature. The MSIVs were closed with SG pressures at about 800 psia. The manual closure of the MSIVs was a conservative action that minimized the cooldown of the RCS. If the operators had not manually closed the MSIVs, a steam generator isolation signal would have automatically closed them at a SG steam pressure of 685 psia and restored RCS temperatures.

Decreasing RCS temperature after a reactor trip is a potential concern due to the positive reactivity from moderator and fuel temperature feedbacks. This positive reactivity addition will erode the negative reactivity added by insertion of the control element assemblies. The Updated Final Safety Analysis Report safety analysis for a main steam line break inside and outside of the containment

analyze such event scenarios. The outside containment main steam line break event analysis bounds this particular event. It concludes that the negative reactivity added by the control element assemblies will be sufficient to maintain the reactor subcritical.

2. Both SGFPs tripped (one automatically, one manually), requiring the manual initiation of the electric-driven AFW train. This resulted in AFW becoming the source of feed to the SGs. The manual initiation of AFW was a conservative action that minimized the potential for a low SG level during the trip recovery. Automatic actuation of the AFW System occurs when either SG reaches a level of -170 inches.

3. Atmospheric Dump Valves 11 and 12 relieved steam at different rates resulting in SG levels decreasing at different rates. This problem had no effect on the ability of AFW pumps to deliver feedwater to the SGs, the ability of operators to manually control the feed rate to each SG, or the ability of Auxiliary Feedwater Actuation System to actuate and make up SG levels when one SG reached a level of -170 inches.

The plant condition that resulted from this event is bounded by the Updated Final Safety Analysis Report Safety analysis concerning main steam line break. The main steam line break analysis assumes a variety of break sizes and locations and concludes that the reactor will remain subcritical in all cases. Based on the discussion above, this event did not result in a significant threat to the health and safety of the public or onsite personnel.

C. GENERIC IMPLICATIONS

At the time of the event, a total of four FP 2000 series controllers with unshielded cabling were installed in Units 1 and 2 (two in each unit) in functions that could cause reactor trips. In addition, there are eight other FP 2000 series controllers (four in each unit) whose failure could pose a challenge to

operators but are unlikely to cause a plant trip. Finally, there are fourteen newer FP 5000 series controllers installed in non--safety related applications. The failure of any of the FP 5000 controllers would not result in a plant trip or loss of a safety system.

The actual likelihood of a repeat occurrence of a FP 2000 series failure caused by EMI could not be quantified. However, it is reasonable to infer a low failure rate under the EMI environment prevailing in the Control Room based on the fact that only one known failure of this type has been experienced since installation of the digital feedwater system in 1993. Walkdowns of the panel wiring for the above controllers indicates several instances where the unshielded controller wiring is routed in proximity to other cabling that may occasionally behave as "EMI aggressor circuits." However, none of these locations can be specifically singled out as a future source of EMI-induced faults.

IV. CORRECTIVE ACTIONS AND RECOMMENDATIONS

A. CONCERNING FIC-1111

1. The procedures governing the plant modification process at the time the digital feedwater upgrade was implemented did not specifically require consideration of the effects of EMI or RFI on instrumentation, nor did they contain any special guidance on the implementation of modifications that would incorporate digital equipment into the plant. These procedures have since been superseded and now require consideration of the effects of EMI and RFI during modification design.

We are reviewing appropriate design engineering standards to ensure adequate design guidance exists concerning protection from the effects of EMI and RFI.

2. We are currently in the process of replacing the existing FP 2000 series digital controllers with newer FP 5000 series controllers. The new controllers are more reliable,

available, and flexible with respect to accepting new software. The new FP 5000 series controllers are also better protected from EMI and RFI. The 2000 series controllers in the feedwater system were replaced on Unit 1 during the last refueling outage and are scheduled for replacement on Unit 2 during its next refueling outage. The new design utilized a "fail over scheme" with two controllers for each control function. If the primary controller fails, operators may bypass it and use the other controller to maintain control of the feedwater system. Electromagnetic interference/RFI filters have also been added to the new controllers.

B. TRIPPING OF SGFPs

Analysis indicates that by slowing the post trip closure rate of the FRVs, the peak SGFP discharge pressure is significantly lowered. Unit 1 has been modified to allow a 4.25 percent/second closure rate for the FRVs, and a similar modification is planned for Unit 2. These modifications should preclude any future SGFP trips on high discharge pressure following a reactor trip.

C. MSR SECOND STAGE SOURCE VALVES

A Preventative Maintenance Reptask was developed as a result of the Preventative Maintenance Optimization Review for the system containing pressure switches 1-PS-4025 and 4026. The Preventative Maintenance Optimization Program was established to review the preventative maintenance repetition tasks in key Calvert Cliffs systems and determine if these or additional reptasks need to be added, deleted, or modified to improve system performance.

A Reptask currently requires calibration and inspections of these pressure switches on a 6 year frequency and will be adjusted based on performance.

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D. FEEDWATER BYPASS VALVE INDICATION

The sticking FRBV limit switch was replaced and other FRBVs limit switches were checked for proper operation.

E. ADV STEAM DISCHARGE AT DIFFERENT RATES

A preventative maintenance optimization review was completed on the main steam system. A complete evaluation of the ADV preventative maintenance schedule was completed during this process. The frequencies of several preventative maintenances on the ADVs were increased to maintain equipment calibration and to prevent degradation of setpoints due to heat and humidity effects. We feel the increased preventative maintenance frequency will improve ADV performance.

V. ADDITIONAL INFORMATION

A. There have been no previous similar reactor trips involving a failure of the digital feedwater controllers at Calvert Cliffs.

Review of the INPO Network, the NPRDS database, and Fossil Industry databases found six examples of FP 2000 series controller failures. The most recent failure occurred on November 17, 1995, and resulted in the FRVs at St. Lucie freezing in a constant position causing the operators to manually trip the plant. The cause of this failure was a degraded 24 volt power supply to a feedwater controller. The other five failures all involved interruptions in the controllers' power supply, followed by a failure of the controller to reboot. There were no reports of controller failures involving EMI or RFI.

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B. Identification of components and systems described in this report.

IEEE 803 IEEE 805
Component or System EIIS Funct System ID

Atmospheric Dump Valve RV JI
Feedwater Regulating Valve FCV SJ
Feedwater Bypass Valve FCV SJ
Pressure Switch 63 SB
Feedwater Regulating Valve FCO SJ
Controller

Moisture Separator Reheater ISV SB
Source Valves
Steam Generator Feed Pump P SJ
Auxiliary Feedwater Pump P BA
Digital Feedwater Controller DCC SJ

ATTACHMENT TO 9610210166 PAGE 1 OF 1

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BGE
October 10, 1996

U.S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Document Control Desk

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit No. 1; Docket No. 50-317; License No. DPR 53
Licensee Event Report 95-005, Supplement 1
Manual Reactor Trip Due to Increasing SG 11 Water Level

The attached supplemental report is being sent to you as committed in LER 95-005 dated December 12, 1995. Should you have questions regarding this report, we will be pleased to discuss them with you.

Very truly yours,

PEK/CDS/bjd

Attachment

cc: D. A. Brune, Esquire
J. E. Silberg, Esquire
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